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Inducing Multiple Hydraulic Fractures From a Horizontal Wellbore

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ABSTRACT

A series of stimulations were designed to open and propagate natural fractures known to exist along a 2000 foot horizontal well in Wayne County, West Virginia. The stimulations were also designed to induce fractures in the formation as well as propagate the natural fractures by manipulating pressure and injection rates. A number of radioactive tracers were used to determine where fractures were opened and propagated at different injection rates. The tracers were found in fractures in zones other than the one pumped into, a fact considered prima facie evidence that natural fractures with two or more orientations had been opened and propagated. Pressure testing and gas sampling of the isolated zones confirm that fracture communication was accomplished along nearly 1000 feet of borehole by stimulation of one 400 foot long section. A technique for inducing multiple hydraulic fractures with multiple orientations was demonstrated.

BACKGROUND

Horizontal wells are drilled to solve production problems or to improve hydrocarbon recovery efficiency from a particular reservoir. It is believed that the original concept of drilling horizontal wells was to contact more formation in a reservoir which was not a particularly outstanding producer, or which had other production problems. One of the earliest known attempts at horizontal drilling in the United States was that done in the Venango sandstone from a shaft drilled near Franklin, Pennsylvania in 1944. The particular problem being addressed was how to produce the heavy crude oil which had lost its solution gas because of the shallow depth of the formation (less than 500 feet) and thus was produced at slow rates.

References and illustrations at end of paper.

Later efforts addressed themselves to tight, low permeability shales and sandstones which were productive only as a function of the natural fractures which are conduits for the reservoir hydrocarbons. The ideal way to improve recovery efficiency is to increase the total number of natural fractures which can be connected to a single wellbore for drainage. Thus the concept of drilling a well in a particular direction and attaining an inclined angle (40 to 90 degrees) was a logical means of improving upon the recovery efficiency of a vertical wellbore.[1]

A method of improving the gas recovery efficiency of inclined or horizontal wellbore in a naturally fractured reservoir is to extend the geometry and flow capacity of existing fractures as well as create new induced hydraulic fractures. This can best be accomplished by stimulating the natural fractures which exist in the reservoir by inflating them with a non-damaging fluid and propping the inflated fractures to maintain the enhanced flow capacity and to induce additional fractures by increasing the injection rate. This was the technical approach used to stimulate gas recovery from the Devonian shales in the horizontal well. This type of operation can be accomplished quite readily if the right geologic conditions can be found. That condition is generally associated with normal or block faulted areas where multiple fracture directions are generated in association with the faulting. Other conditions where multiple fracture sets are generated are associated with thrust faulted areas. Several geologic settings were selected in Wayne and Lincoln Counties, West Virginia, which were known to have multiple fracture sets as a function of the pre-Cambrian rift-type basement faulting which produced the Rome Trough, and the test well was drilled in one of them.

Little published literature exists which discusses the relationship of the orientation of horizontal or inclined wells with respect to geologic trends of faulting and fracturing expected to be encountered in the wellbore, and their potential impact on stimulation operations. This is one of the prime purposes of this paper.

INTRODUCTION

The purpose of this paper is to acquaint the reader with the theory, technical approach, and the results of a series of hydraulic fracture stimulation tests which were designed to both open and propagate natural fractures, and to induce additional multiple fractures as a preferred method of enhancing production from a low pressure, low permeability gas reservoir.[2]

The well was completed utilizing external casing packers to partition the horizontal wellbore into a number of zones which could be stimulated separately with treatments which would take into account the number and spacing of the natural fractures in the zone (see Figure 1). Analysis of the video camera survey of the wellbore revealed that there were five fracture sets, three of which might be propagated during a stimulation operation.[3] This information was used to design a series of data fracs to obtain information on breakdown pressure, closure pressure, fracture gradient and stress ratio. The results of the data frac indicated multiple closure pressure determinations as suspected.[2] The frac gradient was determined to be 0.25 and 0.31 psi/ft, and the stress ratio to be .20 and .27. This data indicated that the rock strata in the area of the horizontal well is nearly stress relieved.

The objective of the tests conducted and reported on in this paper is to present evidence supporting our conclusion that two sets of natural fractures were opened and propagated during stimulation operations, and induced fractures along a third direction controlled by the regional stress field. Two systems of fracture diagnostics were used to collect data which would either confirm or reject our hypothesis. One was a tilt meter system and the other was the use of radioactive tracer isotopes in the frac fluids and their subsequent detection in the near wellbore environment by the use of the multispectral gamma ray log. In addition, pressure tests and gas sample analysis were used to confirm multiple fracture orientations.

GEOLOGIC SETTING

The test well is located in the west-central plateau region of the Appalachian Basin (see Figure 2). The rock strata generally exhibit a low 1 to 1-1/2 degree dip southeast toward the center of the Basin. The regional dip is interrupted by small amplitude anticlines and synclines with generally less than 300 feet of closure. Faulting of the basement rocks during pre-Cambrian time produced a series of normal faults in the area (Figure 3) which have produced measurable effects of the strata as high as the Devonian age rocks.[4] Superposition of the basement faults on the Lower Huron structure map (Figure 4) shows correspondence with major structural features at this horizon. Structural trends as mapped on the Berea sandstone found above the target Lower Huron shales and production trends from the shales show corresponding with the trends of fracturing and faulting encountered in the well (Figure 5).[3] Previous reservoir characterization studies compiled by Cliffs Minerals, Inc.,[6] in which oriented cores were obtained for study, show that the dominant fracture trends are found in a band between N35°E and N75°E (Figure 6). The trends established from examination of oriented cores from the test well and the examination of the video camera survey show good correspondence with trends of basement faulting in the area (Figure 7).

The area in the vicinity of the well is considerably fractured and faulted from the effects of the basement faulting in the area. This is believed to be the reason for the low stress ratio (ratio of vertical stress to minimum horizontal stress which is an indicator of the ease of fracturing) in the area, a hypothesis supported by Advani and Lee, who projected stress ratios as low as .28 immediately above basement faults as a result of their finite element modeling work.[5] The basement faulting and perhaps episodic movement along the faults has produced multiple fracture trends in the Devonian shales. It is believed that this faulting is one of the primary reasons for the large production trends found in the Big Sandy gas field of eastern Kentucky and southwestern West Virginia. This gas field has produced nearly 3 trillion cubic feet of gas during the past 50 to 60 years and is still under development.

Because of the extensive fracturing, much gas has migrated vertically into shallower formations, producing a low pressured reservoir. Gas reservoir pressure gradient in the area of the test well is 0.16, while the gradient for most Appalachian area reservoirs is 0.30 to 0.36.

HYPOTHESIS FOR FRACTURE GENERATION

Since the area of the horizontal well is characterized geologically as a tectonically relaxed area characterized by normal faulting, the investigators anticipated a low fracture pressure gradient for stimulations on the well. The authors further postulated that in the absence of strong tectonic stresses, it is likely that the multiple fracture orientations observed in the wellbore (N37E, N48E, N57E, and N67E) are within a 15 degree angle with the principal stress orientation (N48 to 52°E) and are likely good conduits for the flow of natural gas. Natural gas was observed flowing from fractures oriented both N37°E and N67°E on the video camera analysis. It seems logical that fractures which permit gas to flow can be inflated and propagated, provided it is done in a fashion which allows the natural fractures which are subparallel to the principal stress to adjust to misaligned intensity vectors. The following hypotheses were constructed for testing during the stimulation operations:

1. When the angle of intersection of a natural fracture trend with the principal stress orientation is less than 32 degrees and the ratio between the two horizontal stress components is less than 2:1, the natural fractures can be inflated, propagated, and propped open to enhance flow capacity.

2. Under low stress ratio conditions, the ideal procedure to inflate natural fractures at low dihedral angles (less than 32 degrees) is to inject the frac fluids at low rates and at pressures which would not exceed 200 psi above closure pressure, or the difference between the boundary unit (above or below) and test unit stresses.

3. High injection rates and pressures will induce fractures oriented and controlled by the regional stress field.

4. Conducting a stimulation treatment in two continuous phases; the first at a low injection rate, and the second at a rate which is two or more times faster than the first rate will produce multipyoriented (multiple hydraulic fractures in a horizontal well where access to the formation is equal to open hole conditions).

5. Since there are likely to be more fractures to be opened and propagated than there is fluid rate available, the natural flow capacity of the fractures will autoselect the fractures to take fluid at any particular time. A few of the highest permeability fractures will take fluid initially and then, as propagation pressure starts to increase, a new set of fractures will be autoselected for injection and propagation and these will have the next highest flow capacity.

6. As the stimulation treatment proceeds, the accumulation of fluid pressure in the system of natural fractures will produce local changes in the stress field, causing different sections of the borehole to accept fluid at different times.

7. The extension of natural fractures with multiple orientations will produce a complex interconnected fracture network which will be a much more efficient drainage system for low permeable shale and siltstone formations than simple parallel multiple hydraulic fractures induced from a horizontal wellbore.

Figure 8 presents a plan view of the postulated fracture system that can be generated at the test well location, which is a function of the stress field and the small dihedral angle natural fracture sets which exist there.

OVERALL TEST PROCEDURES

The objective of the Recovery Efficiency Test is to determine the efficiency of hydrocarbon recovery from a horizontal wellbore encountering natural fractures, and further to determine the utility of inducing multiple hydraulic fractures to improve recovery efficiency. Yost and Overbey[2] discussed in detail the key technical issues addressed by the stimulation experiments and the overall technical approach used in designing and conducting a series of stimulations which examined the parameters of fluid types, volumes, injection rates and pressures.

A series of 11 tests have been conducted to date during the course of 5 stimulations on 4 different zones in the well. A series of different tests were conducted during 3 stimulations on the same zone to be able to make direct comparison of the results of fluid types and injection rates. The series of tests conducted are presented in Table 1.

The results of the tests were measured in two ways: (1) collection of pressure build-up and drawdown data and the use of history matching with 3-dimensional, dual porosity models to determine permeability and the amount of improvement over natural permeability determined before stimulation testing; (2) the use of radioactive isotope tracers as fracture diagnostic material injected during the stimulation tests to determine how many fractures were pumped into during the various tests. Spectral gamma radiation surveys were then run on the well 2 to 27 days after stimulation was completed. An attempt to use tiltmeters as an additional diagnostic tool failed because of rugged terrain and poor surface conditions.

The fracture diagnostic studies conducted on the spectral gamma logs showed the position along the wellbore where tracer laden fluid was injected back into the formation. By using the tracers in the manner we did, we were able to examine the effects of various flow rates and pressures which existed during the treatments.

The test series in Zone 6 was logged by pushing the spectral gamma tool in the hole on a coiled tubing unit. Test series 6 and 7 in Zone 1 was logged with the spectral gamma tool mounted on the outside of 2-3/8" tubing and a side-door sub and wet connect system used to make wireline connections. Test series 8 through 11 were logged by blowing the spectral gamma tool down inside 2-3/8" tubing and then logging back out in a conventional manner. Blowing the tools down is the easiest, most cost effective way to collect fracture diagnostics data. It is quite difficult to make measurements with tubing and wireline strings that seem to correlate any closer than 2 feet, thus making it difficult to point to a positive correlation with any degree of certainty that the natural fracture which is within 2 feet of the location of a fracture indicated by the tracer study is indeed a natural fracture that has been inflated. An illustration of this point is shown in Figure 9 which shows the locations of fractures indicated by spectral gamma tool versus the location of fractures located by video camera survey. Correspondence is pretty close for some of the fractures, but off by more than 2 feet for others.

FRACTURE DIAGNOSTICS

Data Frac Test Series

The first 4 tests on the well were conducted on Zone 6 (see Figure 1). Zone 6 had six natural fractures detected by video camera analysis, mostly near ECP #6 around 4200 feet. The first two tests were nitrogeon gas tests in which the N_2 was injected at 2500 scf/min or 5000 scf/min. No radioactive tracer was used during the gas injection because of the problem with bringing the gas back to the surface with no residence time in the reservoir. The next 2 tests were N_2-foam injected at 5 bpm and 12 bpm. Since these were aqueous fluids, tracers could be used in the treatment. Radioactive iodine 131 was used to stimulate the reservoir rock. Results of the tracer test in Zone 6 is presented in Figure 10. A comparison of the effects of generating fractures as a function of rate is presented in Figure 11. Figure 11A shows the fractures generated in Zone 6 and Zone 5 at low injection rates of 5 bbl/minute. Distribution of the fractures is scattered over 500 feet of wellbore even though injection was through the port collars at 4290 feet. Apparently several of the fractures in Zone 5 propagated away from the wellbore until they intersected a natural fracture that would carry the gas back to the wellbore in another zone such as occurred in Zone 5.

When the injection rate was increased from 5 to 12 barrels/min in test No. 4, new fractures are induced beside old fractures. Fluid from the new fractures finds its way back to the wellbore at 4660 in Zone 5, which is 420 feet down the wellbore (see Figure 11B). The authors interpret this data as verification of hypothesis No. 2 in which multiple natural fractures were open and propagated where they already existed.

Nitrogen Gas Test

Test No. 5 was the injection of a high volume of nitrogen gas at low rates of 8-16 bbl/min (2000-5000 s ft^3/min). Radioactive tracers were not used on this test and the 8 tilt meters installed 3 weeks prior to the test could not be stabilized to collect useable data. As reported in Table 2, the authors assumed that many of the 69 observed natural fractures present in Zone 1, the target reservoir, had been pumped into. Most of the 3745 barrels of nitrogen was pumped at a rate of less than 10 bpm, a rate low enough to allow selection of natural fractures for propagation.

Liquid CO_2 Tests

Tests No. 6 and 7 were injections of liquid CO_2 at 12 and 20 barrels per minute into Zone No. 1. Zone 1, which is 419 feet long, has 69 natural fractures available to receive frac fluid.

Iodine 131 was the tracer used during injection of CO_2 at 12 bbls per minute (Test No. 6). The distribution of fractures induced, or taking fluid, is shown on Figure 12A, and again at the slower rates the frac fluid sought out the natural fractures and these interconnected with other fractures, distributed over 1000 feet of wellbore. When the injection rate was increased to 20 bpm, distribution of the induced fractures was more concentrated (Figure 12B). Fractures induced during Test No. 7 were generally located in areas which had not been injected into during Test No. 6 (see Figure 13).

Since tracer was present in Zones 2, 3, and 4, indicating either the external casing packers (ECP) failed or the fluid traveled to these zones via natural fractures oriented at some angle other than N52°E, a series of pressure tests were taken for each zone to determine if all pressures were equal, which would be the case if the ECPs had failed. The results of the pressure tests presented in Figure 14 show different pressures which is interpreted to mean the packers held and the tracer was conducted to Zones 2, 3, and 4 by natural fractures. To further substantiate this fact, gas samples were taken from each zone after the pressure test and the results presented in Figure 15 show that Zones 2, 3, 4, and 8 were communicated with by the CO_2 injected in Zone 1. The investigators believed that test series 6 and 7 with the results of fracture diagnostic studies, reservoir pressure and gas sampling tests rather convincingly established the validity of hypotheses 2, 3, 4, 5, 6, and 7.

Nitrogen Foam with Proppant

Tests 8 and 9 were injected into Zone 1 at the same low rates of 10 bpm. During Test 8, antimony 124 tracer was injected with the pad. Prior to beginning of Test 8, 112 bbls of liquid CO_2 was injected as a prepad but was not traced. It appears likely that the 4800 gallon CO_2 prepad and the 10,000 gallon pad were injected mostly in the 10 to 12 fractures located between 5730 ft and 5800 ft where the injection ports are located (see Figure 16).

During Test 9, sand laden fluid was also injected in the same fractures to begin with, but other fractures opened up and took fluid and proppant as shown on the iridium track on the spectral gamma log. In addition, 7 fractures were generated between 5650 ft and 5675 ft that had not been opened up before indicating that possibly the sites of fracture propagation were shifting up and down the wellbore as the job progressed and stresses built up in the inflated fractures. Several fractures were opened up which interconnected with fractures in Zone 2 as can be seen on Figure 17. Both pad material and proppant material was transported into fractures located along the wellbore of Zone 2. Very little tracer material was found in Zone 3 and 4 as a result of this low volume, low rate stimulation.

With the completion of Tests 8 and 9, a unique series of stimulation tests were completed in which 3 different fluids (N_2, CO_2, and N_2-foam), a gas, a cryogenic liquid, and a foam were injected at 5 different injection rates and pressures. Bottomhole pressure tests confirmed two and possibly 3 different closure pressures which the investigators attributed to fractures with different orientations with respect to the stress field. This is likely the only time 3 different stimulations have been conducted in the same interval resulting in inducing a different set of fractures each time (see Figure 18).

Large Volume Nitrogen Foam with a Proppant

Tests 10 and 11 are large volume, high rate tests in the combined zones of 2-3, and 4. These tests were conducted by injecting 48,000 gallons of 80 quality foam as a pad at 40 bpm in the case of Test #10; while 90,000 gallons of sand laden, 80 quality foam was injected at 30 bpm during Test No.

11. Scandium 46 was injected as a tracer during Test 11. No tracer was used for Test No. 10. Two hundred twenty-five thousand (225,000) pounds of sand was injected with the foam. Examination of the spectral gamma log run after the test reveals that most of the radioactive traces placed in the proppant stage (Test 11) was injected in Zone 3 and Zone 4. As shown in Figure 19, most of the scandium 46 tracer was injected in sections of zones 3 and 4 which has been previously pumped into during the stimulation on Zone 1 (Test 9) as indicated by the Iridium 192 tracer.

Tracers were not used in the pad stage (Test 10) of this job, so we can only speculate about where the bulk of this material went. Test 10 consisted of 48,000 gallons of 80 quality N_2 foam pumped at 40 bpm while Test 11 consisted of 90,000 gallons of 80 quality foam containing 225,000 lbs of 20/40 mesh sand pumped at 30 bpm. It is believed that most of the pad material was injected into the intervals between 5000 and 5075 ft and 5475 and 5600 ft. These intervals show no fractures indicated by the presence of scandium 46 giving rise to the speculation that the pad material went into these zones and then stress loading of the formation produced a shift in the area being treated (see Figure 20) for the balance of the stimulation. The 54 fractures treated are concentrated in Zones 3 and 4.

DISCUSSION OF RESULTS

Results of the tests are presented in Table 2 in the form of the number of fractures induced during the tests and the overall improvement in production over the natural production rate.

Although the series is not complete at this time, the data analyzed to this point tends to support confirmation of the hypotheses relative to the propagation of multiple-oriented, multiple hydraulic fractures. The jury is still out on the comparison of the effectiveness of fast versus slow rates and high versus low volumes of fluids.

The differences in the distribution of induced fractures as diagnosed by the spectral gamma survey in test series 3-4 (Figure 11), 6-7 (Figure 12) and 8-9 (Figure 18) and injection rate would tend to support hypothesis #2 which says that low pressure-low injection rates in a horizontal wellbore with open hole access will select natural fractures for propagation. Distribution of the fractures propagated seemed more random at low rates than high rates. High rates of injection seem to trigger auto selection by the formation as to spacing and distribution as shown in Figure 20 for the last stimulation.

The tracer studies indicate that fewer fractures (54) were pumped into at high rates (30 bpm) in the last stimulation than the number of fractures (69) pumped into during Test 9 on Stage 1 which was pumped at the slow rate of 10 bpm. It is not clear that this would always be the case.

It seems logical that stimulations in horizontal wells under similar geologic and stress conditions should be planned to take advantage of the natural formation tendencies. The investigators believe that the amount of pad volume could be reduced by 15 to 20 percent of the total volume used. In addition, 2 rates of injection should be used; one at 5 to 10 bpm, which would include pad and proppant treatment, followed by a second stage of pad and proppant volume injected at 20 to 25 bpm. In areas where stress ratios are higher and multiple fracture orientations are lacking, then geology will dictate whether two rates would be advantageous.

As more experience is gained in stimulating horizontal wells in low stress ratio environments, it may be possible to interconnect fractures all along the wellbore by stimulating only specific intervals with tailored rates and pressures.

CONCLUSIONS

(1) The series of stimulation tests performed on the RET #1 well in Wayne County, West Virginia, in the Devonian shale formation and the fracture diagnostics conducted provide conclusive evidence that multiple hydraulic fractures were induced during each pumping event.

(2) Radioactive isotopes can be used effectively to trace flow paths to adjacent zones. The isotopes could not have appeared in these zones without traveling back to the wellbore via fractures of an orientation considerably different than that of the principal stress orientation.

(3) The distribution of fluid entry points determined from tracer logs indicate that natural fractures will be selected at low injection rates (5-10 bpm) while induced fractures will be selected at high injection rates (greater than 25 bpm).

(4) Pressure testing and gas sampling data correlated well with the presence of tracer material in adjacent zones which demonstrate that multiple-oriented hydraulic fractures had been generated and connected along the wellbore.

(5) The use of multiple radioactive isotopes in conducting multiple injection tests to obtain data for stimulation design proved very beneficial in understanding natural versus induced preferred fluid paths.

(6) Multiple-oriented multiple hydraulic fractures can be induced from a horizontal wellbore under openhole wellbore conditions where the natural and induced fracture orientations are ±15°.

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Table 1
Summary of Stimulation Test Series Conducted on RET No. 1 Well

Test No.	Zone	Fluid	Rate	Volume	Frac Diagnostics
1	6	N_2 (Gas)	5 BPM	37 MCF	None
2	6	N_2 (Gas)	15 BPM	212 MCF	None
3	6	N_2 - Foam	5 BPM	100 BBLS	Iodine 131
4	6	N_2 - Foam	12 BPM	300 BBLS	Scandium 46
5	1	N_2 (Gas)	8-16 BPM	3745 BBLS	Tilt Meters
6	1	CO_2 (Liq)	12 BPM	200 BBLS	Iodine 131
7	1	CO_2 (Liq)	20 BPM	400 BBLS	Scandium 46
8	1	N_2 - Foam	10 BPM	166 BBLS	Antimony 124
9	1	N_2 - Foam	10 BPM	595 BBLS	Iridium 192
10	2-3, 4	N_2 - Foam	40 BPM	905 BBLS	None
11	2-3, 4	N_2 - Foam	30 BPM	2142 BBLS	Scandium 46

Table 2
Summary of Results of Stimulation Tests to Inject Into Old Fractures or Create New Ones

Test Number	Zone	Natural Fractures Detected	Fractures Pumped Into	Production Improvement
1	6	6	6 (Assumed not measured)	4.1
2	6	6	6 (Assumed not measured)	4.1
3	6	6	14	4.1
4	6	6	14	4.1
5	1	69	12 (Based on Test 6 results)	5.0
6	1	69	27 (Over 4 zones: 1, 2, 3, 4)	25.0
7	1	69	67 (Over 4 zones: 1, 2, 3, 4)	25.0
8	1	69	17 (Over 3 zones: 1, 2, 3)	15.5
9	1	69	69 (Over 4 zones: 1, 2, 3, 4)	15.5
10	2-3, 4	72	Not determined	(N.D)
11	2-3, 4	72	54 (Over 3 zones: 2, 3, 4)	(N.D)

Completion Configuration

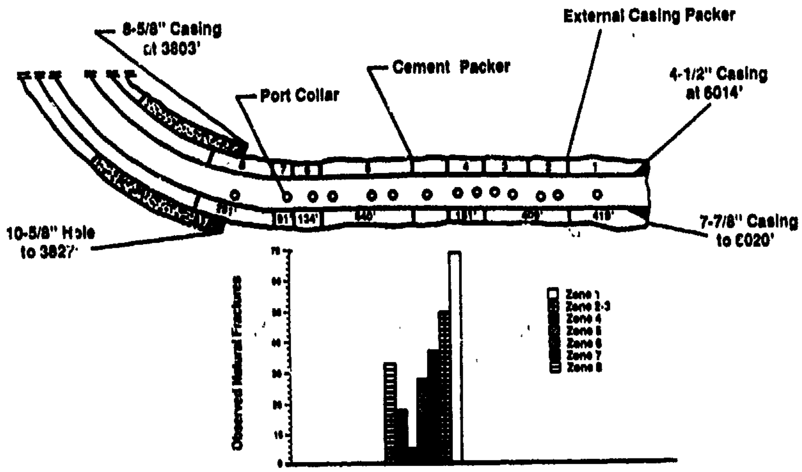


Fig. 1—Horizontal wellbore completion configuration.

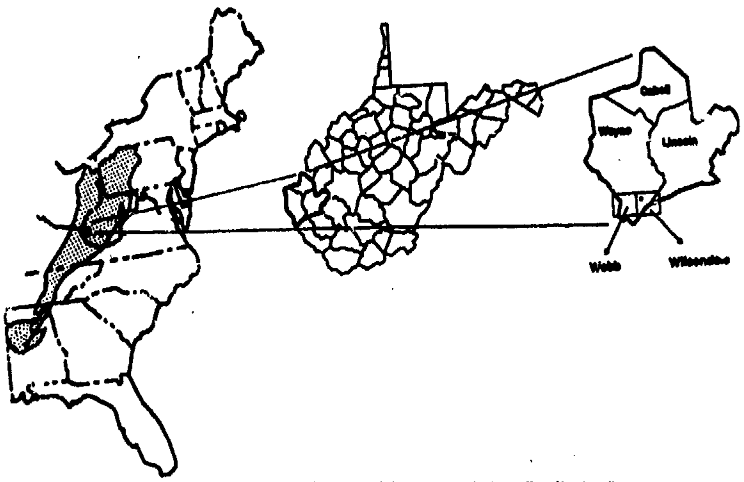


Fig. 2—General location of the recovery efficiency Test No. 1 well.

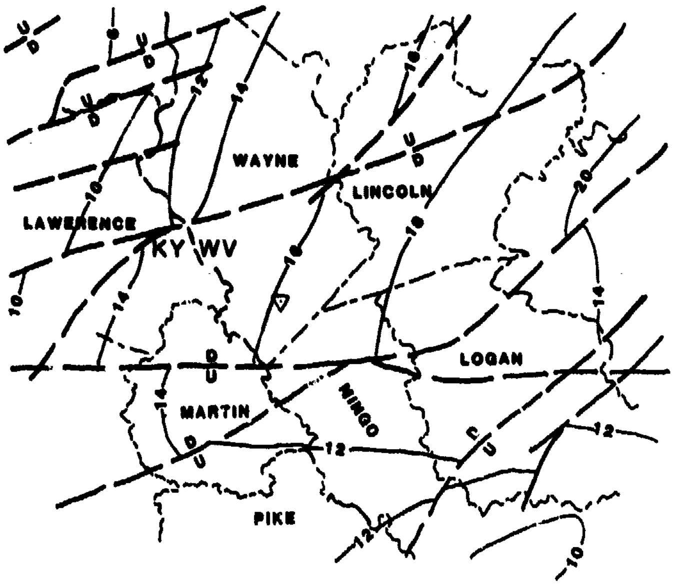


Fig. 3—Structure on pre-Cambrian basement rocks and location of well.

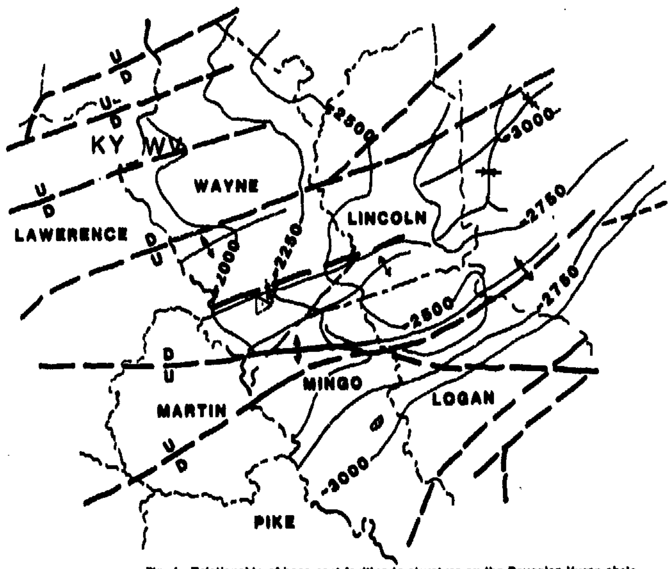


Fig. 4—Relationship of basement faulting to structure on the Devonian Huron shale.

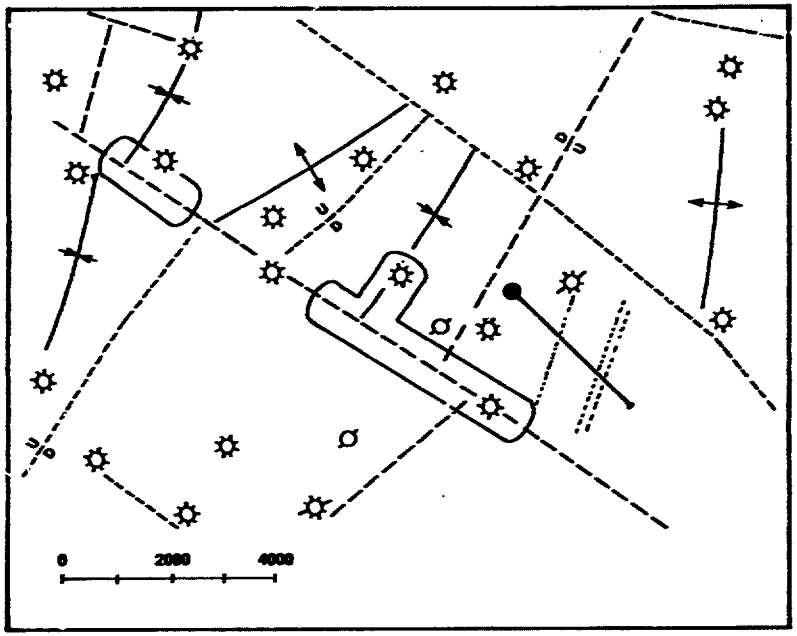


Fig. 5—Local structural elements near the horizontal well.

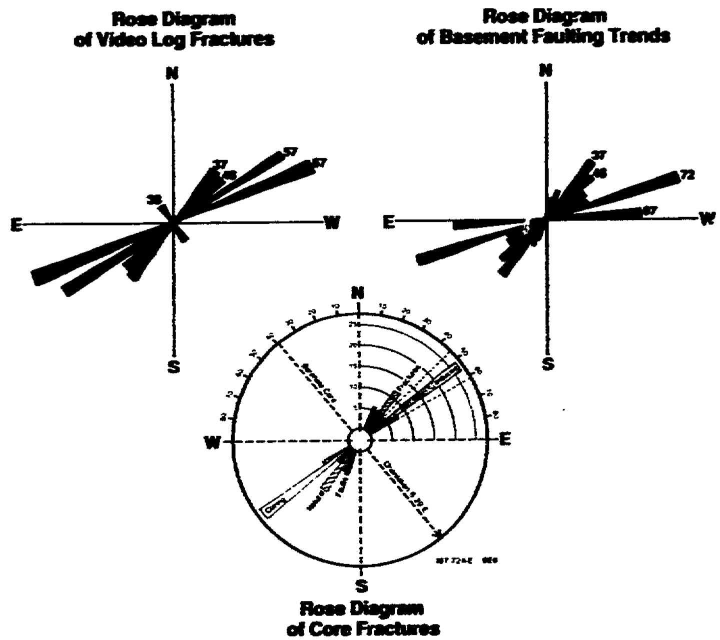


Fig. 7—Comparison of wellbore and core fractures with basement faulting trends.

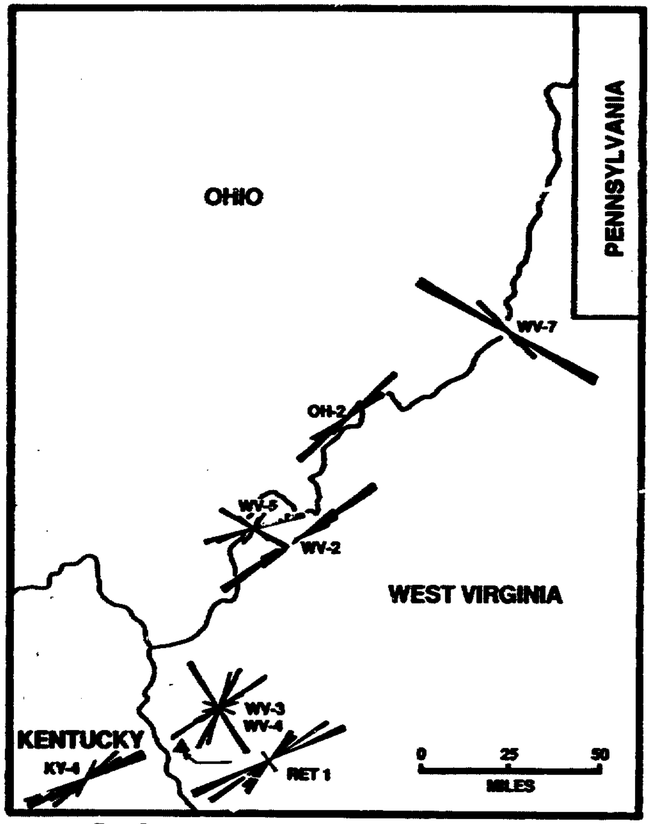


Fig. 6—Fracture trends established from Devonian shale oriented core studies.

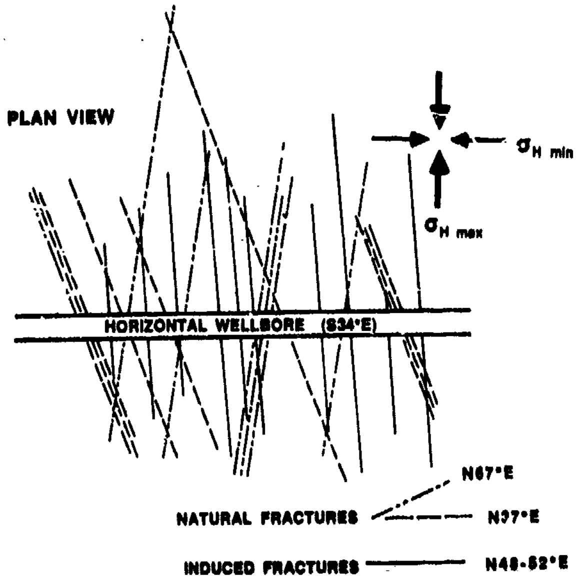


Fig. 8—Diagram illustrating interconnection of small dihedral angle fractures.

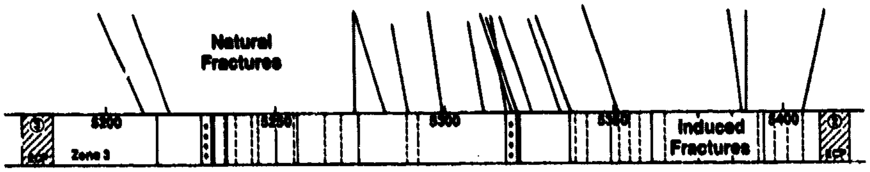


Fig. 9—Relationship of natural fractures to induced fractures.

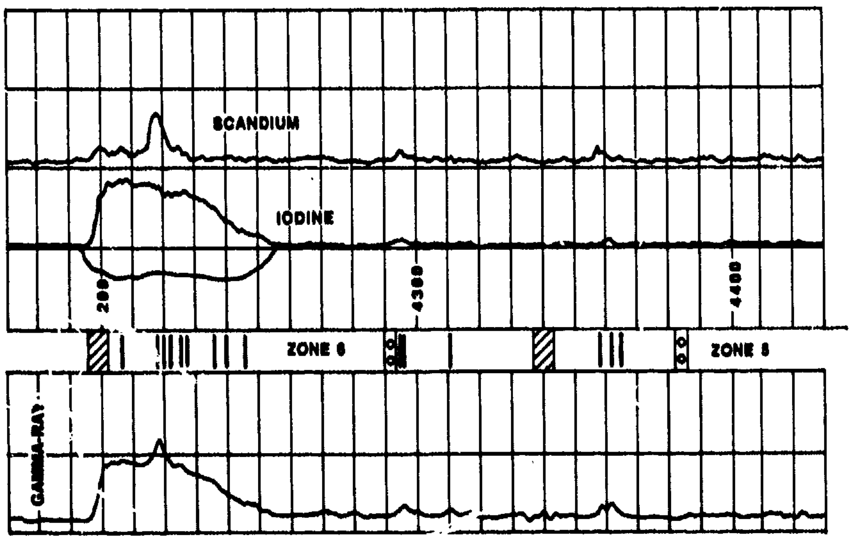
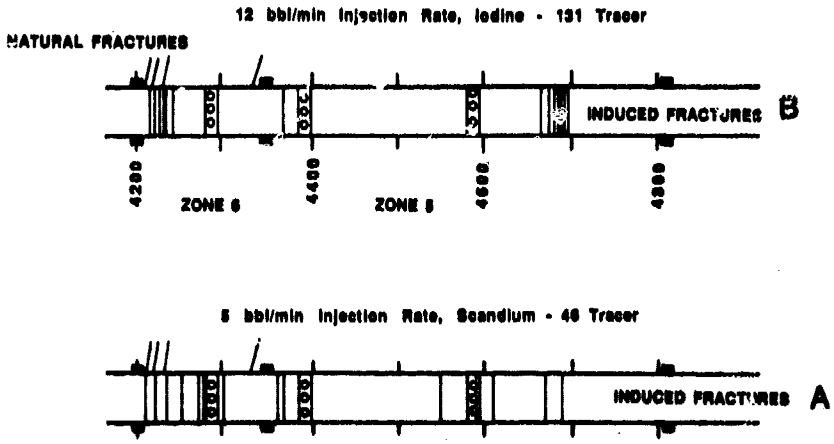


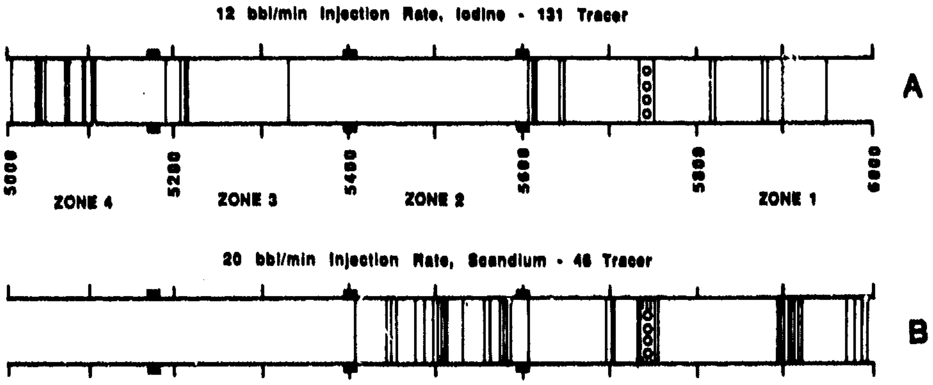
Fig. 10—Spectral gamma log response from dual rate foam injection tool.



ZONE 6 DATA TEST

CLOSURE PRESSURES, 850 & 1050 psig

Fig. 11—Induced fracture spacing as a function of foam injection rate in Zones 5 and 6.



ZONE 1 LIQUID CO2 STIMULATION

CLOSURE PRESSURES, 825 & 880 psig

Fig. 12—Induced fracture spacing as a function of liquid CO_2 injection rate.

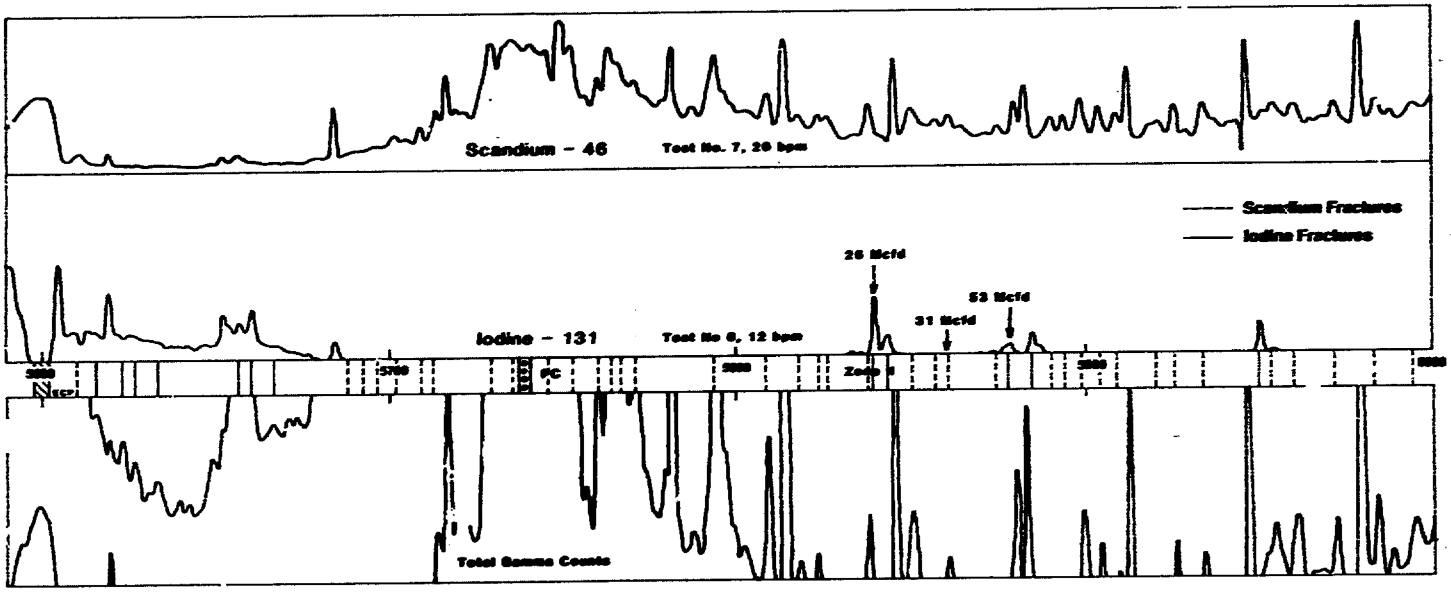


Fig. 13—Spectral gamma log response of tracers used to determine order of fracture generation as a function of injection rate.

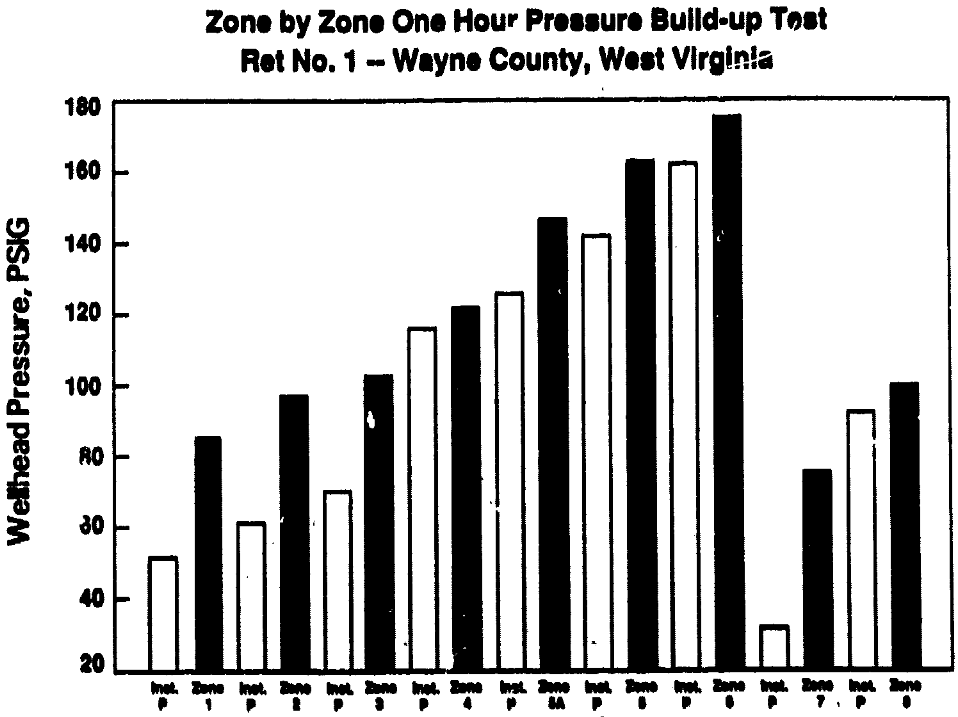


Fig. 14—Pressure buildup response test after CO_2 frac job.

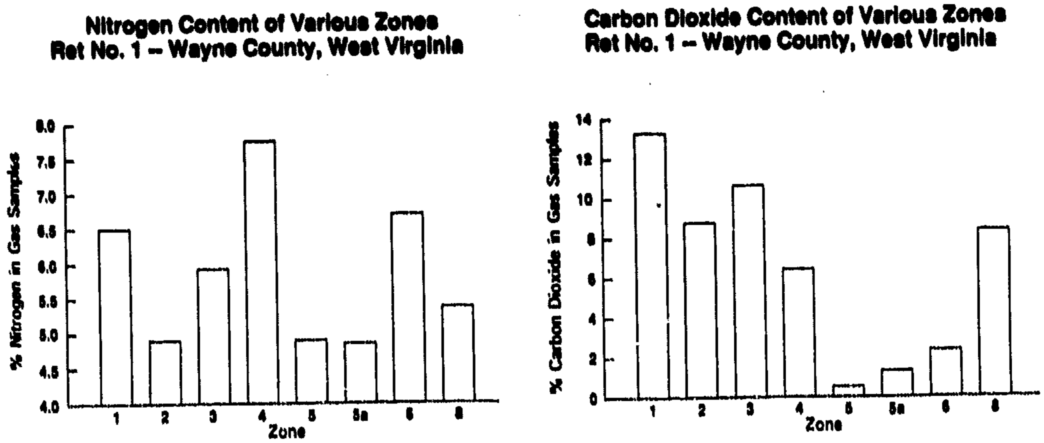
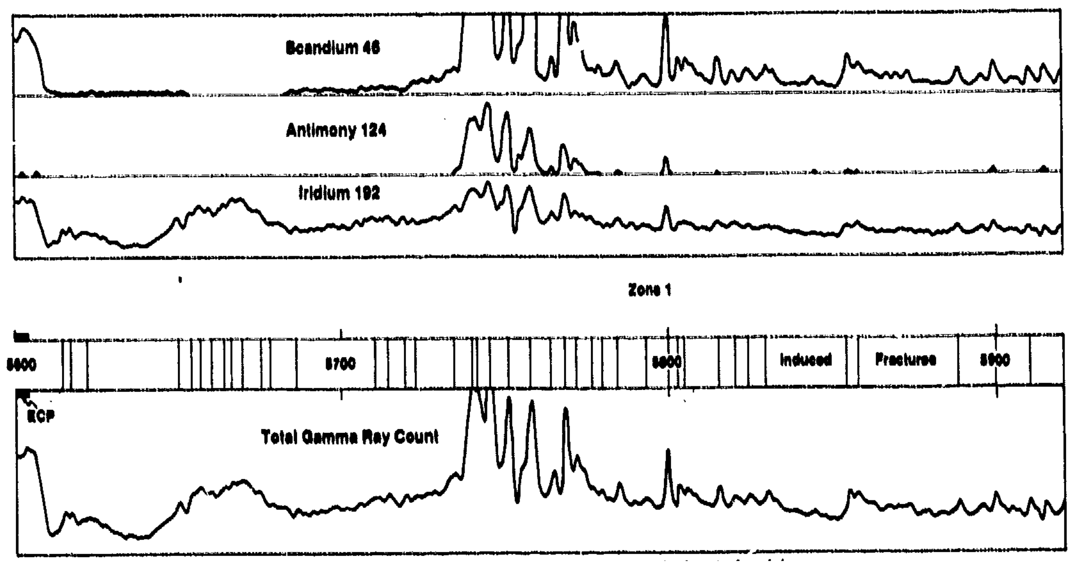


Fig. 15—Gas sample composition by zone to indicate interconnection of zones.



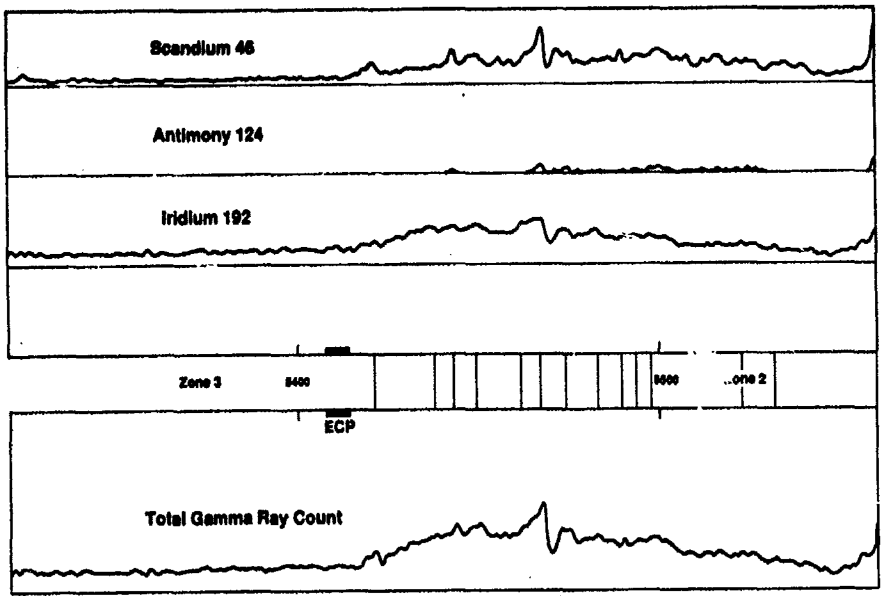


Fig. 17—Spectral gamma ray response of borehole in Zones 2 and 3 after single-rate frac job.

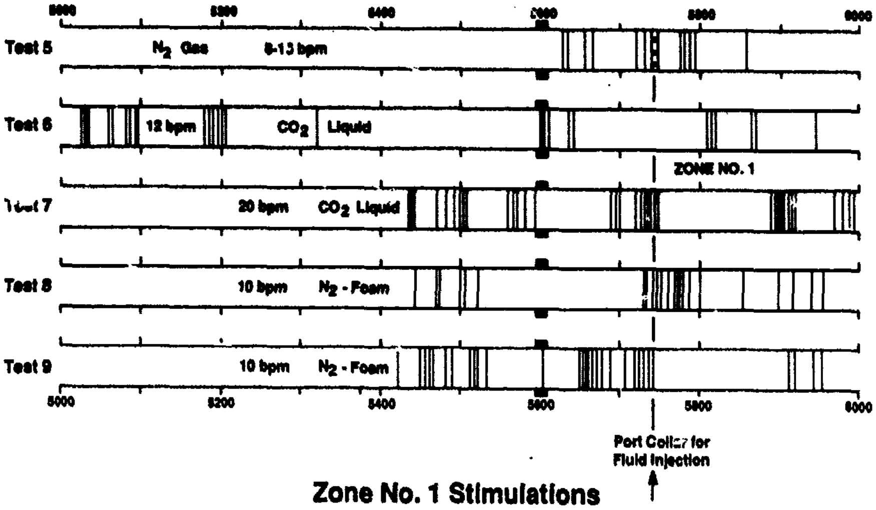


Fig. 18—History of fractures induced during three stimulations of Zone 1.

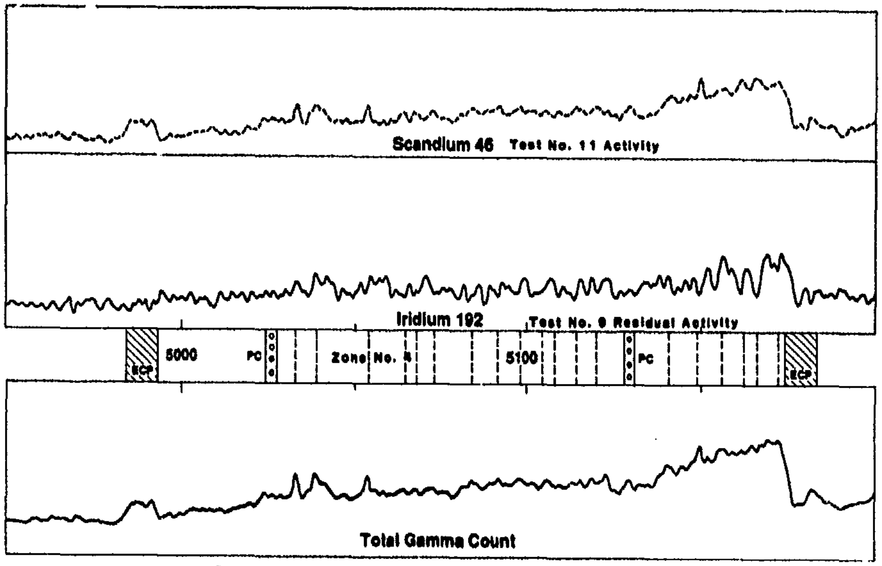
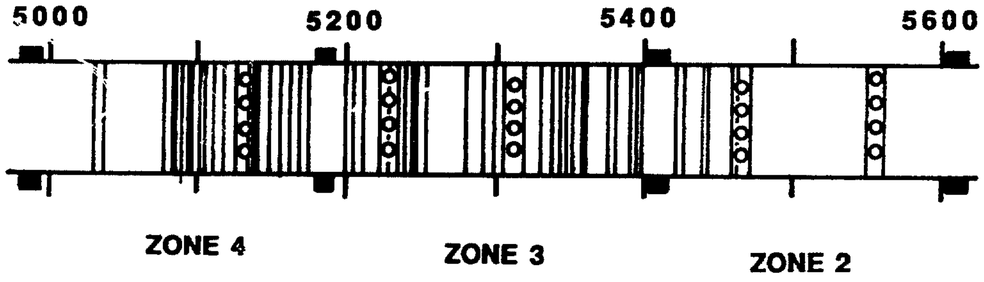


Fig. 19—Spectral gamma response of Zone 4 after high-rate/high-volume frac job.



TEST 11- LARGE VOLUME NITROGEN FOAM FRAC

Injection Rate 30 bbl/min

Fig. 20—Distribution of induced fractures from high-rate/high-volume foam frac.